



Moody's Investors Service
Global Credit Research

Interstate Power Company
Docket #01-0628
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IPC

October 1998

New York

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ELECTRIC UTILITY

Industry Outlook

IP

01-0628

3.3

1/3/02

ELECTRIC UTILITY RATING HISTORY

COMPANY	<1> Current Rating	Date Chgd	1997 Rating	Date Chgd	1996 Rating	Date Chgd	1995 Rating	Date Chgd	1994 Rating	Date Chgd
Alabama Power Company	A1		A1		A1		A1		A1	
<9>AmerenCPS	Aa2	Feb-1998	Aa1		Aa1		Aa1		Aa1	
<9>AmerenUE	Aa3	Feb-1998	A1		A1		A1		A1	
Appalachian Power Company	A3		A3		A3	May-1996	A2		A2	
Arizona Public Service Company	Baa1		Baa1		Baa1		Baa1	May-1995	Baa2	
Atlantic City Electric Company	A3		A3		A3		A3		A3	
Baltimore Gas & Electric Company	A1		A1		A1		A1		A1	
Black Hills Corporation	A1		A1		A1		A1		A1	Aug-1994
Boston Edison Company*	Baa1	Jul-1998	Baa2		Baa2		Baa2		Baa2	
Cambridge Electric Light Company*	Baa2		Baa2		Baa2		Baa2		Baa2	
Canal Electric Company	Baa1		Baa1		Baa1		Baa1		Baa1	
Carolina Power & Light Company	A2		A2		A2		A2		A2	
Central Hudson Gas & Electric Corporation	A2	May-1998	A3		A3		A3		A3	
Central Illinois Light Company	Aa2		Aa2		Aa2		Aa2		Aa2	
Central Maine Power Company	Baa3		Baa3	May-1997	Baa2		Baa2		Baa2	
Central Power and Light Company	A3		A3	Apr-1997	A2		A2		A2	
Central Vermont Public Service Company+	*Baa2*		*Baa2*		*Baa2*		*Baa2*		*Baa2*	
Cincinnati Gas & Electric Company	A3		A3		A3		A3	Nov-1995	Baa1	
<10> Cleco Corporation	A2		A2		A2		A2		A2	
Cleveland Electric Illuminating Company	Ba1		Ba1	Aug-1997	Ba2		Ba2		Ba2	
Columbus Southern Power Company	A3		A3		A3	Aug-1996	Baa1	Jul-1995	Baa2	
Commonwealth Edison Co.	Baa2		Baa2		Baa2		Baa2		Baa2	
Connecticut Light & Power Company, The	Ba2 Ba3	Jul-98 Apr-98	Ba2 Ba1	Dec-97 Apr-97	Baa3 Baa2	Oct-96 May-96	Baa1		Baa1	
Consolidated Edison Company of NY Inc.*	A1		A1		A1		A1	Apr-1995	Aa3	Feb-1994
Consumers Energy Company	Baa3		Baa3		Baa3		Baa3		Baa3	
Dayton Power & Light Company	Aa3		Aa3		Aa3		Aa3	Mar-1995	A1	Mar-1994
Delmarva Power & Light Company	A2		A2		A2		A2		A2	
Detroit Edison Company	A3		A3		A3		A3		A3	
<2>Duke Energy Corp.	Aa3		Aa3	Jul-1997	Aa2		Aa2		Aa2	
Duquesne Light Company	Baa1		Baa1		Baa1		Baa1		Baa1	
Eastern Edison Company	Baa1		Baa1		Baa1		Baa1		Baa1	
El Paso Electric Company	Ba2	Jan-1998	Ba3		Ba3	Jan-1996	Caa		Caa	
Empire District Electric Co., The	A2		A2		A2		A2	Dec-1995	A1	
Entergy Arkansas, Inc.	Baa2		Baa2		Baa2		Baa2		Baa2	
Entergy Gulf States, Inc.	Baa3		Baa3		Baa3		Baa3	Mar-1995	Baa2	
Entergy Louisiana, Inc.	Baa2		Baa2		Baa2		Baa2		Baa2	
Entergy Mississippi, Inc.	Baa2		Baa2		Baa2		Baa2		Baa2	
Entergy New Orleans, Inc.	Baa2		Baa2		Baa2		Baa2		Baa2	
Florida Power Corporation	Aa3		Aa3		Aa3		Aa3		Aa3	
Florida Power & Light	Aa3		Aa3		Aa3	Jun-1996	A1	Jul-1995	A2	
Georgia Power Company	A1		A1		A1		A1	Apr-1995	A2	Apr-1994
Green Mountain Power Corp.	Baa2		Baa2		Baa2		NR		NR	
Gulf Power Company	A1		A1		A1		A1	May-1995	A2	
Hawaiian Electric Company, The	A3		A3		A3		A3		A3	
<3>Houston Industries Inc.	A3		A3		A3	Dec-1996	A2		A2	
<4>IES Utilities Inc.	A2		A2		A2		A2	Jun-1995	A1	Aug-1994
Idaho Power Company	A2		A2		A2		A2		A2	
Illinois Power Company	Baa1		Baa1		Baa1	Jul-1996	Baa2		Baa2	
Indiana Michigan Power Company	Baa1		Baa1		Baa1		Baa1		Baa1	
Indianapolis Power & Light Company	Aa2		Aa2		Aa2		Aa2		Aa2	
Interstate Power Company	A1		A1		A1		A1		A1	
Jersey Central Power & Light Company	Baa1		Baa1		Baa1		Baa1		Baa1	Aug-1994
Kansas City Power & Light Company	A1		A1		A1		A1		A1	Jan-1994
Kansas Gas and Electric Co.	A3		A3		A3		A3		A3	
Kentucky Power Company	Baa1		Baa1		Baa1		Baa1		Baa1	
Kentucky Utilities Co.	Aa2		Aa2		Aa2		Aa2		Aa2	
Louisville Gas & Electric Company	Aa2		Aa2		Aa2		Aa2		Aa2	
Madison Gas & Electric Company	Aa2		Aa2		Aa2		Aa2		Aa2	

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ELECTRIC UTILITY RATING HISTORY (cont'd)

COMPANY	<1> Current Rating	Date Chgd	1997 Rating	Date Chgd	1996 Rating	Date Chgd	1995 Rating	Date Chgd	1994 Rating	Date Chgd
Massachusetts Electric Company	A1	—	A1	Dec-1997	A2	Aug-1996	A1	—	A1	—
Metropolitan Edison Company	Baa1	—	Baa1	—	Baa1	—	Baa1	—	Baa1	Aug-1994
<5>MidAmerican Energy Company*	A3	—	A3	Jan-1997	A2	—	A2	Jul-1995	A1	—
<11>Minnesota Power, Inc.	Baa1	—	Baa1	—	Baa1	Mar-1996	A3	Mar-1995	A2	—
Mississippi Power Company	Aa3	—	Aa3	—	Aa3	—	Aa3	—	Aa3	May-1994
Monongahela Power Company	A1	—	A1	—	A1	—	A1	May-1995	Aa3	—
Montana Power Company	Baa1	—	Baa1	—	Baa1	—	Baa1	—	Baa1	—
Narragansett Electric Company	A1	—	A1	Dec-1997	A2	Aug-1996	A1	—	A1	—
Nevada Power Company	Baa2	—	Baa2	—	Baa2	—	Baa2	—	Baa2	—
New England Power Company	A1	—	A1	Dec-1997	A2	Aug-1996	A1	—	A1	—
New York State Electric & Gas Corporation	Baa1	—	Baa1	—	Baa1	—	Baa1	—	Baa1	Nov-1994
Niagara Mohawk Power Corporation	Ba1 Ba2	Apr-98 Feb-98	Ba3	—	Ba3	Apr-1996	Ba1 Baa3	Oct-95 May-95	Baa2	—
Northern Indiana Public Service Company	A2	—	A2	—	A2	Feb-1996	A3	—	A3	—
Northern States Power Co. (Minnesota)	Aa3	—	Aa3	Jul-1997	A1	—	A1	—	A1	May-1994
<12>Northwestern Corporation	A1	—	A1	Jan-1997	A2	—	A2	Jul-1995	Aa3	—
Ohio Edison Company	Baa2	—	Baa2	—	Baa2	—	Baa2	—	Baa2	—
Ohio Power Company	A3	—	A3	—	A3	—	A3	—	A3	—
Oklahoma Gas & Electric Company	Aa3	—	Aa3	May-1997	A1	—	A1	—	A1	—
Orange & Rockland Utilities, Inc.	A3	—	A3	—	A3	—	A3	—	A3	Jun-1994
Otter Tail Power Company	Aa3	—	Aa3	—	Aa3	—	Aa3	—	Aa3	—
Pacific Gas & Electric Company	A1	—	A1	Jun-1997	A2	—	A2	—	A2	Dec-1994
PacifiCorp	A2	—	A2	—	A2	—	A2	—	A2	Sep-1994
<6>PECO Energy Company	Baa1	—	Baa1	—	Baa1	—	Baa1	—	Baa1	—
Pennsylvania Electric Company	A3	—	A3	—	A3	—	A3	—	A3	Aug-1994
<7>PP&L, Inc.	A3	—	A3	—	A3	—	A3	Oct-1995	A2	—
Pennsylvania Power Company	Baa2	—	Baa2	—	Baa2	—	Baa2	—	Baa2	—
Portland General Electric Company	A2	—	A2	—	A2	Mar-1996	A3	May-1995	Baa1	—
Potomac Edison Company	A1	—	A1	—	A1	—	A1	May-1995	Aa3	—
Potomac Electric Power Company	A1	—	A1	—	A1	—	A1	—	A1	—
PSI Energy, Inc.	A3	—	A3	—	A3	—	A3	Nov-1995	Baa1	—
Public Service Company of Colorado	A3	—	A3	—	A3	Nov-1996	Baa1	—	Baa1	—
Public Service Company of New Hampshire	Ba3	—	Ba3	Mar-1997	Ba1	—	Ba1	Oct-1995	Baa3	—
Public Service Company of New Mexico	Ba1	—	Ba1	—	Ba1	Sep-1996	Ba2	—	Ba2	—
Public Service Company of Oklahoma	A1	Mar-1998	Aa3	—	Aa3	—	Aa3	Mar-1995	Aa2	—
Public Service Electric and Gas Company	A3	—	A3	—	A3	Jan-1996	A2	—	A2	—
Puget Sound Energy, Inc.	Baa1	—	Baa1	Feb-1997	A3	—	A3	—	A3	—
Rochester Gas & Electric Corporation	A3	May-1998	Baa1	—	Baa1	—	Baa1	—	Baa1	—
San Diego Gas & Electric Company	A1	—	A1	—	A1	—	A1	—	A1	Dec-1994
Savannah Electric & Power Company	A1	—	A1	—	A1	—	A1	—	A1	—
Sierra Pacific Power Company	A3	—	A3	—	A3	—	A3	—	A3	—
South Carolina Electric & Gas Company	A1	—	A1	—	A1	—	A1	—	A1	—
Southern California Edison Company	A1	—	A1	Jun-1997	A2	—	A2	—	A2	Dec-1994
Southern Indiana Gas & Electric Company	Aa2	—	Aa2	—	Aa2	—	Aa2	—	Aa2	—
Southwestern Electric Power Company	Aa3	—	Aa3	Apr-1997	Aa2	—	Aa2	—	Aa2	—
Southwestern Public Service Company	Aa2	—	Aa2	—	Aa2	—	Aa2	—	Aa2	—
System Energy Resources Inc.	Baa3	—	Baa3	—	Baa3	—	Baa3	—	Baa3	—
Tampa Electric Company	Aa2	—	Aa2	—	Aa2	—	Aa2	Apr-1995	Aa1	—
Tennessee Valley Authority*	Aaa	—	Aaa	—	Aaa	—	Aaa	—	Aaa	—
Texas Utilities Electric Company	Baa1	—	Baa1	Jan-1997	Baa2	—	Baa2	—	Baa2	—
Texas-New Mexico Power Company	Ba2	—	Ba2	—	Ba2	Oct-1996	Ba3	—	Ba3	—
Toledo Edison Company	Ba1	—	Ba1	Aug-1997	Ba2	—	Ba2	—	Ba2	—
Tucson Electric Power Company	Ba3	—	Ba3	—	Ba3	—	Ba3	Mar-1995	B1	—
United Illuminating Company	Baa3	—	Baa3	—	Baa3	—	Baa3	—	Baa3	—
UtiliCorp United Inc.*	Baa3	—	Baa3	—	Baa3	—	Baa3	—	Baa3	—
Virginia Electric and Power Company	A2	—	A2	—	A2	—	A2	—	A2	—
Washington Water Power Company	A3	—	A3	—	A3	—	A3	—	A3	—
West Penn Power Company	A1	—	A1	—	A1	—	A1	May-1995	Aa3	—
West Texas Utilities Company	A2	—	A2	Apr-1997	A1	—	A1 Aa3	Sep-95 Mar-95	Aa2	—
Western Massachusetts Electric Company	Ba2 Ba3	Jul-98 Apr-98	Ba2 Ba1	Dec-97 Apr-97	Baa3 Baa2	Oct-96 May-96	Baa1	—	Baa1	—
<8> Western Resources Inc.	A3	—	A3	—	A3	—	A3	—	A3	—
Wisconsin Electric Power Company	Aa2	—	Aa2	—	Aa2	—	Aa2	—	Aa2	—
Wisconsin Power and Light Company	Aa2	—	Aa2	—	Aa2	—	Aa2	—	Aa2	—
Wisconsin Public Service Corporation	Aa2	—	Aa2	—	Aa2	—	Aa2	—	Aa2	—

* Senior Unsecured Rating

+ Preferred Stock Rating

<1> As of October 1, 1998.

<2> Previously known as Duke Power Company.

<3> Previously known as Houston Lighting & Power Company.

<4> Formed by merger of Iowa Electric Light & Power Company and Iowa Southern Utilities Company on December 31, 1993.

<5> Formed as a result of merger between Midwest Resources Inc. and Iowa Illinois Gas & Electric on July 1, 1995.

<6> Previously known as Philadelphia Electric Company before March 1, 1995.

<7> Previously known as Pennsylvania Power & Light Company.

<8> Formed as a result of Kansas Gas & Electric merger with Kansas Power & Light effective 3/31/92.

<9> Formed as a result of Central Illinois Public Service merger with Union Electric effective 2/27/98.

<10> Previously known as Central Louisiana Electric Company.

<11> Previously known as Minnesota Power & Light Company.

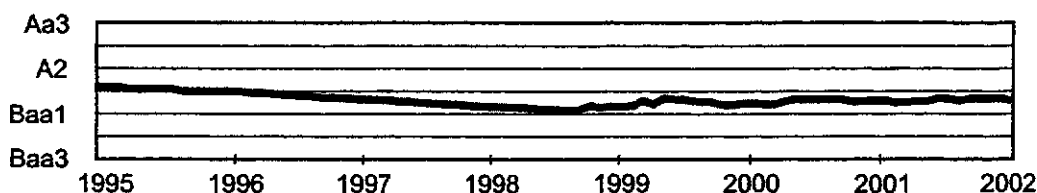
<12> Previously known as Northwestern Public Service Company.

Electric Utility Industry Outlook

Ratings (Continued)

Category	Moody's Rating	Analyst	Phone
The Industry Group includes 121 Companies.		Jonathan Cohen	June Lee (212) 553-1653
		Jeff Davidson	Kevin Rose
		Julia M. Doetsch	A.J. Sabatelle
		Emily Eisenlohr	Mo Ying Seto
		A. Tucker Hackett	Scott Solomon
		Edward Ip	Susan D. Abbott
		Andy Jacobyansky	Michael Foley
		Robert Johnson	

Rating History



Operating Statistics

Industry Average Ratios

	1993	1994	1995	1996	1997	Forecast		
						1998	1999	2000
ROE(Avg.)(%)	9.8	10.3	16.0	12.1	11.4	11.0	10.9	11.1
Operating Margin (%)	16.3	16.2	17.2	16.7	15.6	15.9	15.5	15.0
Pre-Tax Int. Cov. (x)	3.2	3.3	3.5	3.7	3.8	3.9	4.0	3.7
Fixed Charge Cov. (x)	2.8	2.9	3.1	3.3	3.3	3.4	3.4	3.2
RCF/Gross Capex(%)	103.4	110.1	131.5	149.4	136.3	142.6	149.1	141.9

Balance Sheet Statistics

Industry Average Ratios

	1993	1994	1995	1996	1997	Forecast		
						1998	1999	2000
Total Capital (\$bil.)	3.3	3.3	3.4	3.3	3.3	3.1	3.0	2.8
Total Debt/Capital (%)	51.1	51.1	50.8	49.7	49.9	48.9	48.2	47.5
Pfd/Capital (%)	6.5	6.3	5.7	5.3	5.4	5.6	5.4	5.1
Common/Capital (%)	42.4	42.6	43.5	45.0	44.7	45.5	46.4	47.4

Opinion

Moody's expects the average rating of U.S. electric utilities, currently at a weak A3, to improve over the next three to five years. But, at the same time, the currently narrow dispersion of ratings around the mean will widen significantly as issuers pursue vastly different business strategies, entailing vastly different risk profiles. In short, the average will become less and less representative.

The firming up of credit quality for some utilities will be the net result of legislation, regulation, and corporate restructuring plans that have dramatically reduced uncertainty concerning their ability to continue to recover all of their fixed costs through rates in an open market. As part of these plans, many are selling their generating assets to non-utility operators, increasing free cash flow, and shedding business risk in the process.

But for every seller, there must be a buyer, and a number of utilities have chosen the opposite tack, creating a niche for themselves in generation and adding assets at an astounding rate. Many of these generating companies are stand-alone issuers or, if part of a "utility family", constitute legal entities that carry ratings reflective of their own business and financial risks separate from the regulated utility. Yet other companies have chosen to focus on, or add to, their repertoire of new business lines such as power marketing and trading, and energy services, which must be assessed based on their attendant risks and rewards.

And so, six years into the transition to a competitive environment, electric utilities are no longer a homogeneous universe. As "distribution" comes to describe the function of the "electric utility" and as electric, gas, telephone, cable and other "distribution services" converge, the concept of

an industry that generates, transmits, and distributes electrons becomes increasingly archaic. This is not to say that some utilities will not choose to continue to provide all three of these formerly vertically integrated services, but they will also provide much more — including gas, telephone, Internet and home security services — and will be differently organized. Understanding the creditworthiness of the distribution company, where a bondholder may be the obligor, and its relationship to and risk from association with a sister generating company of which the bondholder is not an obligor is a more complex issue than the assessment of a vertically integrated utility.

This industry outlook attempts to bring clarity to an industry in transition and to the issues bondholders must be aware of in assessing potential investment in any portion of an "electric utility" family. Choices being made now concerning corporate structure and lines of business will have enormous bearing on credit quality for years to come given the differences in risk in each business. And because of the changing nature of the industry and new threat of competition, management strategy, talent, and depth will also take on a greater-than-ever role in the level of success achieved by any company. While regulation is no longer THE most important issue in the long term fortunes of a utility family group, regulatory and legislative initiatives during the transition can have lasting effects on a company's financial flexibility. Combined further with the potential volatility introduced by participation in an unregulated commodity market, the need for careful cash flow analysis of the risks being taken on by any given company becomes more critical than ever.

More Certain Stranded Cost Recovery Improves Outlook

In the years following the passage of the National Energy Policy Act in 1992, Moody's cautioned investors about the potential for significant downward pressure on the credit quality of many investor-owned utilities as retail markets for electric power were opened to competition. Our concerns about credit quality were driven largely by persistent uncertainty about the extent to which utilities could recover their fixed costs in prices dictated by competitive markets.

More recently, however, regulatory and legislative initiatives have considerably reduced this uncertainty, leading us to a somewhat more optimistic view of the future direction of the industry's average credit quality. Legislation and regulatory restructuring plans enacted to date have, for the most part, allowed for the phase-in of retail competition over a multi-year transition period, and have provided utilities the opportunity to recover their fixed and sunk costs through the divestiture of generating assets, a non-bypassable charge to existing customers, and/or securitization.

SIGNIFICANT HEADWAY TOWARD COMPETITION AT STATE LEVEL

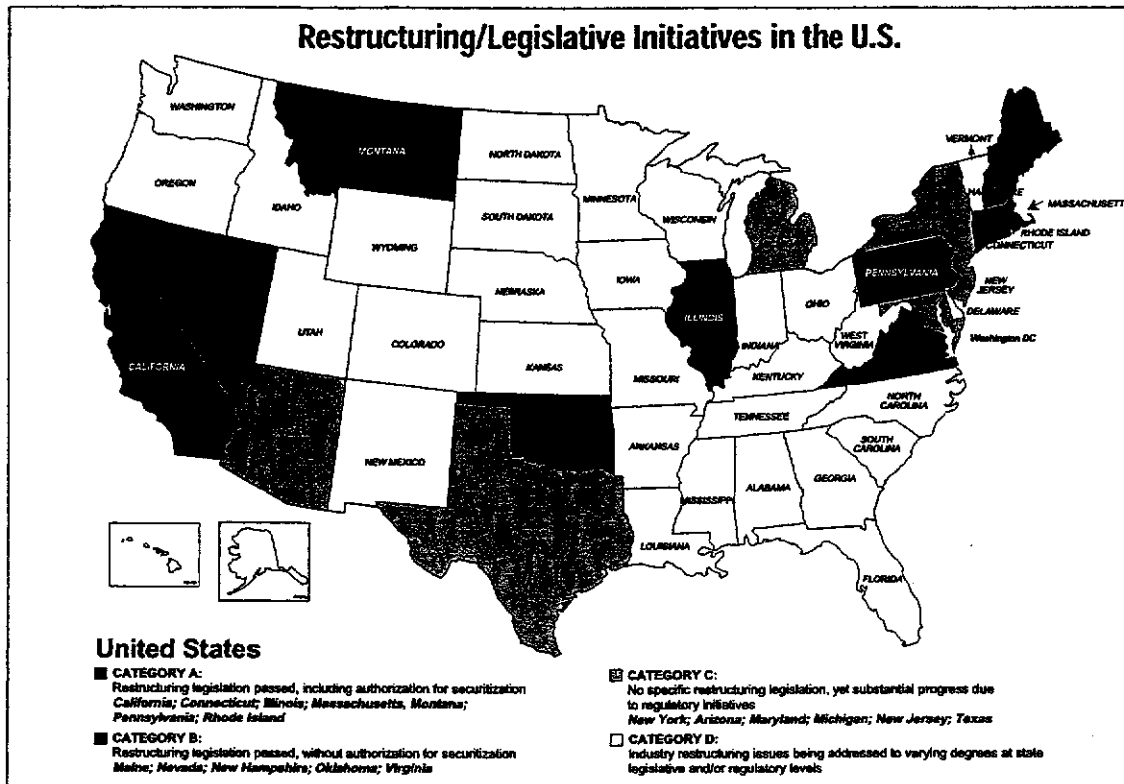
Legislation concerning retail competition has been passed in 12 states, including California and five Northeast states in which electric rates have been the highest. For the most part, these laws have been supportive of the utilities in their quest for full recovery of costs that might be rendered uneconomic, or "stranded", under competition. The notable exception is New Hampshire, where progress toward retail competition has been stalled by court battles between the state's utilities and its regulators over legislation that does not provide for full recovery of stranded costs. Similar court battles currently prevail in Vermont, although the state is still without restructuring legislation.

Even absent legislation in some states, there has still been considerable progress toward establishing retail competition as a result of regulatory support for individual utility restructuring plans. In New York, for instance, six of the seven utilities have obtained regulatory approval for their own restructuring plan. The seventh New York-based utility, KeySpan Energy (formerly Long Island Lighting Company) has recently completed its version of an electric restructuring plan by selling all but its wholly-owned generating units and gas business to the Long Island Power Authority. Michigan is commencing choice in 1998 under orders issued by the Michigan Public Service Commission.

With very few exceptions, we expect that most of the other states will continue to debate electric utility restructuring issues at the state legislative level. As many of these states press hard toward enacting their own versions of electric restructuring laws, they are likely to incorporate those aspects of laws already passed that they think will work best for them, while adding their own unique conditions.

We expect that electric utility restructuring will also remain a high priority agenda item in the next Congressional session, as all signs indicate that there will be insufficient support to pass any one of the several bills that were floating in Congress this year. Among the obstacles to progress at the federal level are difficulties in coming to grips with how and/or whether to reform the Public Utility Holding Company Act of 1935 and certain sections of the Public Utility Regulatory Policy Act of 1978, as well as lingering questions about federal versus state jurisdictional matters. If the states continue to make good progress with regard to bringing about electric industry restructuring, then the push for Congress to do something could begin to wane.

With or without legislation, the pace at which the restructuring process moves in any given state is likely to be influenced by the extent to which politicians are willing to get involved, to which customers are discontent with the current rates that they are paying to the incumbent utility, and to which the companies are satisfied with the process. We have found that it is particularly helpful when legislation is in place because it helps guide the regulatory process involved in bringing a utility's restructuring plans to fruition. Indeed, in many instances, the legislators are deferring to the regulators to implement the details of how restructuring will work in a given state.



PLANS OFFER CUSTOMERS AND COMPANIES CHOICES

To date, utility restructuring plans have often incorporated a phase-in approach to retail competition, in many instances allowing time for pilot or test programs involving certain groups of customers to determine whether a particular approach works. Although some plans have tried to stretch the phase in period out well beyond the year 2000, there still appears to be a strong preference to keep the phase in period as short as practically possible (generally not later than 2002).

Other key aspects to utility restructuring plans that we have seen to date include commitments to divest all non-nuclear generating assets and to reduce rates by an average of 10% in exchange for an opportunity to fully recover any costs stranded or rendered uneconomic by the onset of retail competition. Although many of the decisions to divest generating assets have been voluntary, there are some instances where utilities were legislatively mandated to do so. The market valuation of assets through the sale process tends to eliminate the contentiousness often associated with relying on a "formulaic" approach to determine the level of stranded costs a utility might have to try and recover by making assumptions about the future price of energy and capacity in a given region.

We expect that regulators will continue to play an important role in many instances when it comes to quantifying the amount of stranded costs that a given utility is left with after divestiture and/or other mitigating steps are taken (e.g., cost reduction programs, using excess earnings above a specified level to accelerate depreciation of generating plants, or faster amortization of regulatory assets).

Once the amount of unmitigatable stranded cost is determined, regulators will then take into account the rules set out by legislation in determining the means by which, the extent to which, and the time frame over which such costs can be recovered. When the rules include an opportunity to periodically "true-up" the stranded cost amount during the transition period, we believe there is less risk present for fixed-income investors.

The most common way that legislators and regulators are permitting stranded costs to be recovered is through the collection of a non-bypassable charge, often referred to as a Competitive Transition Charge (CTC), over a predetermined time period (e.g., the transition period). This fee is established as one part of the unbundled rates charged by companies continuing to provide regulated "wires" services.

For those companies that retain interests in nuclear generating assets, many plans allow these assets to remain part of the regulated transmission and distribution utility. Under this approach, costs relating to these investments will continue to be recovered in the regulated rates that these entities charge their customers through the transition period. These investments will continue to be recovered in the regulated (and often frozen) rates.

THOUGH CONTROVERSIAL, SECURITIZATION REMAINS CREDIT POSITIVE

Yet another comprehensive and considerably more controversial means by which companies can recover their stranded costs is through securitization. Securitization is an option currently available to utilities in seven of the twelve states that have passed restructuring legislation to date. This is not to suggest that the subject has not been hotly contested throughout the country. In some states, such as New York, this is an issue that is clearly divided across political party lines, which makes passage of legislation that specifically provides for securitization more difficult.

In general, securitization legislation permits utilities to create a property right to the revenue stream produced by collection of the non-bypassable competitive transition charge. The property rights are then sold to a special purpose financing vehicle or bankruptcy remote trust. This entity can then issue securities backed by the future cash flows from the CTC's.

We view the credit implications for utilities who issue securitized bonds to be positive due to the expected lower financing costs of higher rated securities and the greater certainty for recovery of stranded costs than existed previously. Just how positive such a financing strategy might be for a utility will, however, depend on how aggressive they are with regard to use of proceeds and the ensuing level of protection that remains for the existing investors in the utility's traditional fixed-income securities. The utility can use proceeds from the issuance of securitized bonds in a variety of different ways, but typically they have indicated that they will pay down debt and buy back common equity in amounts that allow them to, at a minimum, maintain the same percentage of debt, preferred stock, and common equity in their capital structure as existed prior to issuing the securitized bonds.

As we analyze utilities that issue securitized bonds, we will treat such bonds as being fully non-recourse to the utility even though the Securities and Exchange Commission's guidelines require the debt to appear on the company's balance sheet. Thus, we will adjust funds from operations and retained cash flow downward to reflect the fact that a material portion of cash flow each year will be set aside for debt service on the securitized bonds. This approach, we believe, will better represent the cash flow stream available to protect the utility's remaining fixed income investors.

When securitization is not an option and/or where generating asset divestiture is not part of the utility's strategy, the company will likely be looking to reduced costs and increased sales as means to offset the rate reductions that are still being required in exchange for regulatory support for restructuring plans. This is more apt to be an approach followed by utilities with only moderate exposure to stranded costs and/or where significant cost reduction opportunities and sales growth potential still exist.

Sale of Generating Assets Reduces Business Risk

Moody's believes that the electric utilities that divest their generating assets, either by choice or regulatory mandate, will substantially reduce their business and financial risks, allowing for the possibility of strengthening their balance sheets and increasing free cash flow.

Divestiture of generating assets has proved to be an effective way to address regulator's market power concerns. It also provides a means to arrive at a firm measure of, as well as a potential mitigant for, stranded costs. Regulators and legislators in New England, for example, have offered utilities a deal that, so far, few have been able to refuse — divest stipulated generating assets in exchange for an opportunity to fully recover stranded costs. Alternatively, regulators in California, by setting low rates of return on equity, have given utilities in that state added incentive to divest. And, in the end, the utilities that divest will be spared the pressures of competition facing the generating side of the business as transmission and distribution continues to be regulated.

It should come as no surprise then that over ten percent of investor-owned electric utility generating capacity in the U.S. is either currently available for auction or has recently been sold.

Yet another compelling reason to divest—and quickly before the market changes—is the significant premiums to book value that buyers have been willing to pay, particularly in the Northeast. In this region, initial concerns that prices would come in below book value have largely dissipated with the results of the first and second waves of auction activity having been so favorable.

Aside from external pressures to exit the generation business, internal motivations come into play as companies make strategic decisions that reflect both their understanding of market conditions and ability to capitalize on perceived strengths and resources. There are a number of conditions that influence this choice, including the supply and demand outlook in a specific service territory, the market cost of electricity, the pace of industry restructuring, labor costs and composition of its workforce. Further, utilities need to decide if divested assets are required elements for the utilities' growth strategy. In many instances, the decision to divest generation assets is a de facto indication that the regulated utility's future business will be focused on the delivery of energy, and that the ownership risks of generation are not commensurate with the rewards available.

While many states have required divestiture of generating assets in their restructuring legislation, Moody's expects that most utilities will not fully exit the generation business. Over the near term for example, companies with nuclear assets will retain this portion of their generating portfolio, at least until a more robust market for these assets develops. In addition, few restructuring schemes have required divestiture of such assets.

ASSET SALES ATTRACT NEW PLAYERS

For every seller there must be a buyer, which means that for every company that wishes to exit the generating business, there is another company with the opposite strategy of expanding its presence in that segment even given the attendant risks. Companies in the Northeast are tending to lean in one strategic direction—exit the generation business to the fullest extent possible, and focus on the distribution and wires business. Other companies in the U.S., like PG&E Corporation and Edison International in California, are simultaneously divesting their formerly regulated generation assets, while acquiring generation assets in the Northeast as a means to stay invested in the generating business on the non-regulated side.

Almost all asset sales to date have been to other investor-owned entities, a trend Moody's expects to continue. One notable exception, however, is the sale by the former LILCO of all of its assets except its wholly-owned generating units and gas assets to a municipal entity.

All sales have not, however, been to existing players. As regulated utilities begin to exit the generation side of their business, new, outside players have entered this market. These new entrants believe that they can be the higher-value owners of generating assets, especially in a competitive market.

Independent power producers (IPPs), though not the only interested parties, have shown the greatest interest in acquiring generation assets. IPPs with some type of IOU affiliation have been the most successful bidders to date.

In some of the larger, more recent acquisitions or announcements in which assets have been put up for sale, the buyer was a geographical outsider: USGen acquired NEES's assets; FPL Group agreed to buy Central Maine Power's assets, Sithe Energies obtained Boston Edison's non-nuclear assets, and Edison International has agreed to acquire GPU/Energy East's mammoth Homer City generation plant. All prices offered were well above the book value for these assets, although the actual value of these assets will hinge on the future market price of generation.

Asset valuation is not limited to the quality of the generating asset. In fact, sometimes the real value to a buyer may be the site, and not the plant, because of the expansion opportunities. The value is also determined by assessing the contracts and obligations the buyer assumes and can not always be analyzed from a \$/MW or book value multiple. Specifically, items such as environmental liabilities, fuel contracts, power sales contracts, and standard offer obligations influence the profitability of a plant. Production costs, regulatory environment, competitive position, and overall market attractiveness are also influential in arriving at an acquisition price.

USE OF PROCEEDS KEY CREDIT FACTOR FOR SELLER

While Moody's generally views the sale of generation assets positively, the manner in which the proceeds from these transactions are used could, in some cases, have negative implications for credit quality. Options for the use of proceeds range from reducing outstanding debt, which has the most positive credit

implications, to buying out purchase power contracts, funding internal capital requirements and promised decreased electric rates, investing in core competencies and strategic initiatives, and to repurchasing stock or sending a special dividend up to shareholders. Used to extreme, the latter two alternatives may have a negative impact on the company's credit quality.

The Californian legislation stipulated that proceeds from generation divestiture or stranded cost securitization could be employed in any manner the utility deemed appropriate, as long as the utilities maintain a capital structure no worse than before legislation was enacted. This restriction was actually a credit positive, insofar as it effectively mandated that the utilities in that state maintain their strong capital base. Niagara Mohawk's commitment to use a significant amount of the proceeds from their auction to repay debt was similarly viewed as a credit positive.

It is becoming increasingly evident, however, that utilities without specific restrictions on the use of proceeds do not necessarily plan to use funds to pay down debt on a pro-rata basis to the way the asset was financed. Many have chosen not to commit to a specific use for the funds.

New Corporate Identities Create New Risk Profiles

As companies determine their future lines of business — from a pure transmission and distribution company, to a pure generating company or independent power producer, to a diversified energy services company — their overall credit quality will change in concert to reflect a new balance of financial and operating risks. Therefore, even though the industry average credit rating is likely to strengthen over the next few years, deviation from the average is also likely to increase as a reflection of the industry's new diversity.

"ONE-NOTCH" RULE NO LONGER APPROPRIATE TO HOLDING COMPANIES

We believe that the common practice of rating an electric utility holding company just one refined rating category (or "notch") lower than the unsecured rating of the core utility is becoming less and less appropriate due to growing complexity in the corporate structure of these companies.

Over the past decade, investor-owned utilities have set up holding companies to expand investment in non-regulated businesses. These investments range from service businesses to telephone companies to foreign utilities to mergers with natural gas companies as part of the convergence of these two energy sectors.

Many utility holding companies have financed substantial portions of these non-regulated investments with debt. While this type of debt has grown, the size of the dividend stream from the primary operating company (the utility) has not, and in fact may be shrinking. The addition of debt to finance non-regulated businesses at either the holding company, affiliates, or elsewhere within the corporation increases risk within the consolidated credit profile.

Structural subordination is one of the basic considerations in rating complex corporate structures. Risks to investors at a shell holding company (which owns just financial assets, usually stock) are different from those faced by investors at its operating company subsidiaries. Holding company debt is serviced almost exclusively by dividends from operating companies. Because dividends are paid after operating company debt service, holding company bondholders and lenders are "structurally subordinated" to operating company bondholders and lenders.

Moody's reflects this legally weaker position by rating holding company debt at least one notch lower than unsecured debt (that is two notches off the senior secured debt) of the utility.

Today, the appearance of numerous new subsidiaries, concurrent with heightened risk from non-regulated businesses, complicates the holding company credit profile. And it complicates credit analysis with regard to the utility operating company. It is now rare that a utility can be analyzed based upon its own credit fundamentals alone.

From a credit perspective, the rating assigned to a holding company must reflect the consolidated risk of the corporation, which in all likelihood will continue to lead to a wider rating differential between members of the same corporate family than has been seen in the past.

STABLE CASH FLOWS, LOWER BUSINESS RISK DISTINGUISH TRANSMISSION AND DISTRIBUTION

The electric utilities that divest their generating assets will substantially reduce their business risk, as well as strengthen their balance sheets and increase free cash flow. All other fundamental factors being equal,

as metering and customer billing. Marketing will continue to be an important function in a customer-oriented market. As a result, gathering and storing data on customer preferences and purchasing patterns will provide an extremely valuable marketing tool in the newly competitive landscape.

Contrary to pure wires companies, aggregators that contract for energy purchases or are involved in the energy trading and sales business will be exposed to highly volatile market prices. As a result, the aggregators will likely exhibit thin margins and uncertain cash flows due to fluctuating market prices in different regions of the U. S., stemming from seasonal energy demand and the availability of capacity resources.

Core competencies necessary for success as an aggregator are: current information on the operating performance of regional generating assets and the market prices these facilities can command during different time and seasonal intervals; marketing sophistication; derivatives expertise to manage price risks; and technical knowledge in maximizing utilization of regional transmission grids, despite certain constraints, during peak and off-peak periods.

CASH FLOW VOLATILITY IS GREATEST CHALLENGE TO GENERATING COMPANIES

In a competitive world, generating companies will face and be held responsible for weather risks, management mistakes, customer demands, environmental liabilities, capital rationing, over-capacity, under-capacity, and technological obsolescence. Each of these risks will affect the cash flow of the company as it struggles to deal with new challenges. Furthermore, as electricity prices are deregulated, the wholesale customer will see volatility in prices as experienced in other industrial commodity businesses like basic chemicals, metals and petroleum markets. Moody's view is that electricity prices will broadly track economic activity in the US in general, but vary regionally as generating companies seek to maximize profits by taking advantage of local market dynamics. This segmentation of the national market portends periods of high volatility in pricing on a regional basis. In addition, classic cyclical industry over-and-under supply conditions are bound to prevail from time to time, adding to price volatility. In the long term, generating companies will need flexible cost and capital structures which allow them to respond to a changing market in order to maintain a steady cash flow stream in a competitive environment.

Cash flow volatility for a generating company can be described by its extremes. The most predictable cash flow is derived from a fixed price, fixed volume contract which is traditionally found in single asset financings. Most contracts of this type contain provisions that require a unit to be "available" in order to qualify for its fixed price to be paid. Current achievements in availability factors which allow for 90% availability in most cases and higher than 95% in some, provide for excellent predictability of cash flow. Assuming continued operating excellence, the power generation assets with contracted revenues provide dependable cash flows which allow for greater creditor confidence at higher debt levels.

In contrast, the least predictable cash flow for a generating company is that of a merchant plant — a plant selling into a competitive market without the benefit of a contract. Merchant plant cash flows are directly affected by price movements and changes in demand and offer the greatest challenge to investors in generating companies. In order to mitigate some of the price risk of merchant activities, generating companies sometimes undertake a partial contract — that is a contract for fixed volumes at a market price, or variable volumes at a fixed price.

Cash flow volatility can also be mitigated by participating in power trading markets through derivative products such as swaps and options. As volumes grow in the power marketing arena companies will be able to forego contracts in favor of a derivative product which offers the same cash flow characteristics. While growth in this market may be slowed by the events of June, 1998, the market is likely to become healthier as the number of market participants decreases and the credit quality of those participants increases.

ASSET PURCHASE PRICES INFLUENCE CASH FLOW

However a generating company acquires its assets — whether they are contributed by a utility into a wholly owned generating subsidiary, spun off into a stand-alone generating company, acquired through public auction, or via a private transaction — the purchase price paid for the asset will be a major cash flow determinant, with bargain price equating to a higher cash flow and a competitive advantage. In the regulated world where acquisition prices would be largely recovered from rate payers, prices were not scrutinized to the degree that they are currently now that buyers can ill afford to ignore things like transmission paths, load pockets, and siting issues.

PORTFOLIO DIVERSIFICATION REDUCES CASH FLOW VOLATILITY

The single most effective mitigant for increased price volatility is increased earnings power created through a large and diversified portfolio of generation projects. Such earnings potential will not, however, be easily achieved. Diversification helps dampen the damaging effect of price volatility suffered by any one plant. However, the ability to add high quality assets to a company's portfolio requires a high degree of financial flexibility and discipline through which management exercises the will to reject transactions that offer unacceptable risk-adjusted rates of return. Such hurdles make it difficult for a small, struggling generating company to add assets to its portfolio in order to improve its cash flow position.

Whether operating in the merchant or contract market, the benefits associated with portfolio diversification are an important cash flow determinant. Financing structures which spread risk across a number of markets, long term contracts with financially sound customers, and efficient or innovative generating technologies will, from a cash flow standpoint, be powerful. For example, investment-grade rated generating companies such as National Power plc (rated A2 senior unsecured) and PowerGen plc (Aa3 senior unsecured) in the United Kingdom, and Endesa (Baa1 senior unsecured) and Chilgener S.A. (Baa1 senior unsecured) in Chile are active in open markets, have competitive cost structures, contracts that are structured prudently to protect against non-operating risks, and conservatively financed investments in various overseas infrastructure projects. This combination of factors supports good to high levels of financial flexibility.

YOUNG AND DIVERSE ESCO UNIVERSE REQUIRES "BOTTOM-UP" ANALYSIS

The term "ESCO" may have a different meaning from one person to the next. That is because the term functions as a catch-all for any company involved in energy-related services outside of the ownership of assets through which electrons flow. In other words, an ESCO is not a generation, transmission, or distribution company. ESCOs would include companies engaged in energy-related equipment leasing; plant or project management, energy efficiency auditing, metering, billing, or any number of other services to other electric companies or their customers.

ESCOs are presently highly fragmented, small, privately-owned businesses. However, the size and visibility of ESCOs are likely to grow over the next decade in response to the need for new products and the rewards for providing them that competitive markets promise. Investment in energy service companies continues to grow, attracted by new profit potential from lack of regulation. Several firms are pursuing aggregation of small ESCOs in similar business lines to achieve national economies of scale (in a strategic thrust called a "roll-up").

As ESCOs lack a peer group for direct comparison, Moody's will rate them "from the bottom up" through detailed fundamental analysis. Cross-comparisons that are normally valuable analytic tools where a peer group exists would likely be inappropriate and misleading with ESCOs as their quantitative measures, such as operating margins, interest coverage, and leverage, can vary widely based on the size and the type of investment required by the sector in which they specialize.

Examples of types of ESCO investments demonstrate the diversity of these companies.

- DTE Energy is pursuing a non-regulated strategy that draws on its core competencies in fuel management developed in the regulated arena. Through subsidiaries, it processes coal into coke for the steel industry, invests in regional rail transportation, markets mid-stream coal in the northern US, and invests in regional generation assets that allow DTE to capitalize on related synergies.
- "One Bill" strategies of slightly different scope are being pursued by KN Energy and Washington Water Power. A KN Energy venture simplifies customer billing by aggregating billing for multiple utility services (electric, gas, cable, telephone, internet, and security) into one bill. WWP's Avista Advantage Customer Internet Site integrates reporting of real time energy usage for its national customers with proprietary technology that analyzes the data for energy savings opportunities while also consolidating utility bills.
- FirstEnergy is accumulating a nationwide network of energy service companies specialized in high volume energy management for commercial and industrial customers through acquisition of small, privately held, regionally based companies. This network will advise its clients on energy cost reduction in high volume air conditioning, heating, lighting, and other forms of energy consumption; provide equipment; and service the equipment over its lifetime.

PRICE SHOCKS HIGHLIGHT RISKS IN POWER MARKETING

Perhaps the highest risk segment of the electric utility industry is power marketing, which just this past summer experienced a "forced" correction to previously exponential sales growth. Still, Moody's expects that unregulated energy trading will continue to grow, even though the risks inherent in power trading will not disappear. Those who choose to stay in the business will strengthen their risk management practices as needed, and those who do not choose to devote the resources necessary for success in trading will exit it. Moody's also believes consolidation to achieve economies of scale will be an integral part of the restructuring of this industry.

Certainly not all of the more than 400 approved power marketers actively trade, but many more were active than were prepared to manage the substantial risks involved when in June 1998 electricity prices in the Midwest skyrocketed to \$7,000 per megawatt-hour. (This translates into \$7 per kilowatt-hour for those who prefer comparison with the residential price, which averaged around nine cents per kilowatt-hour in 1997.) FirstEnergy, PacifiCorp, Illinova, and Wisconsin Electric among others announced trading losses during the second quarter. However, some firms announced trading gains, having either anticipated market developments, moved swiftly and deftly, or were blessed with excess capacity at a time when capacity was at a premium.

The confluence of many factors – some certain, some of moderate probability, and a few totally unexpected – created the unusual price movement.

- Several large plants were out of service, reducing regional capacity.
- Two other plants were knocked out of service by storms, further reducing capacity.
- A heat wave spread across an enormous region, preventing the usual sharing of capacity among regions to deal with normal heat waves.
- One power marketer credit failure (Federal Energy Sales) led to another (Power Company of America), causing credit concerns within the market. Firms reduced their trading to only those counterparties willing to put up sufficient formal protections or up-front payments, reducing liquidity.
- Failures to deliver resulted in purchasers being forced to cover positions with spot market priced power, aggravating the price spikes.
- Some inexperienced trading firms panicked and bought power to cover future potential settlements while prices remained elevated.

Many utilities have asked the Federal Energy Regulatory Commission (FERC), which licenses power marketers to trade at market-based rates, to set financial parameters as part of licensing criteria. Certainly protections are necessary for the small and unsophisticated purchasers, such as residential and small commercial customers. But Moody's is concerned that if FERC were to appear to add financial strength criteria to its requirements, many larger market participants, including trading firms, may in effect rely upon the FERC to do their counterparty risk management, thereby neglecting this key risk management task. Such a request may be indicative of an industry with an inherited culture of regulatory protection. Few other corporations engaged in competitive markets expect or desire a regulatory body to manage their supplier risks.

In order for investors to understand the risks that can develop with regard to counterparty transactions—which we highlighted in our December 1997 Special Comment on the power marketing segment—one first needs to know that every contract entered into has an offsetting contract to eliminate risk. Otherwise the trading firm would be carrying an open exposure to market price fluctuations. However, if Counterparty B fails to deliver contracted power to Trading Firm A, the nominal amount of the contract may not be the only loss. Even though Trading Firm A could justifiably not perform on subsequent contracts with that counterparty, the trading firm would still have to cover the exposure gaps created by cancellation of these remaining contracts.

If the market moves substantially against those exposure gaps, the trading firm may be forced to cover the exposures at a substantial loss. This is what occurred for several parties exposed to contracts with both Federal Energy Sales and Power Company of America in June. And it is a type of risk that if poorly managed, could still create large losses, even for firms which claim to be limiting their risk exposures and trade "just for customers".

Power marketers also have minimal hard assets. In bankruptcy they could repudiate all contracts which entail losses (as they are legally executory contracts) and keep those with gains, leaving those who file claims against the bankrupt firm battling over limited proceeds.

Among the other credit risks highlighted in the power marketer failures of June is that of relying upon name alone, with its associated perception of creditworthiness. As we cautioned last December, when trading becomes difficult, only strong and reliable credit supports can be counted on to protect against counterparty risks. The Power Company of America, which ranked 21st in power marketer sales in 1997, was affiliated with both Barr Devlin Associates, its general partner which is one of the top investment banking firms to the electric energy sector, and with two GE affiliates as limited partners.

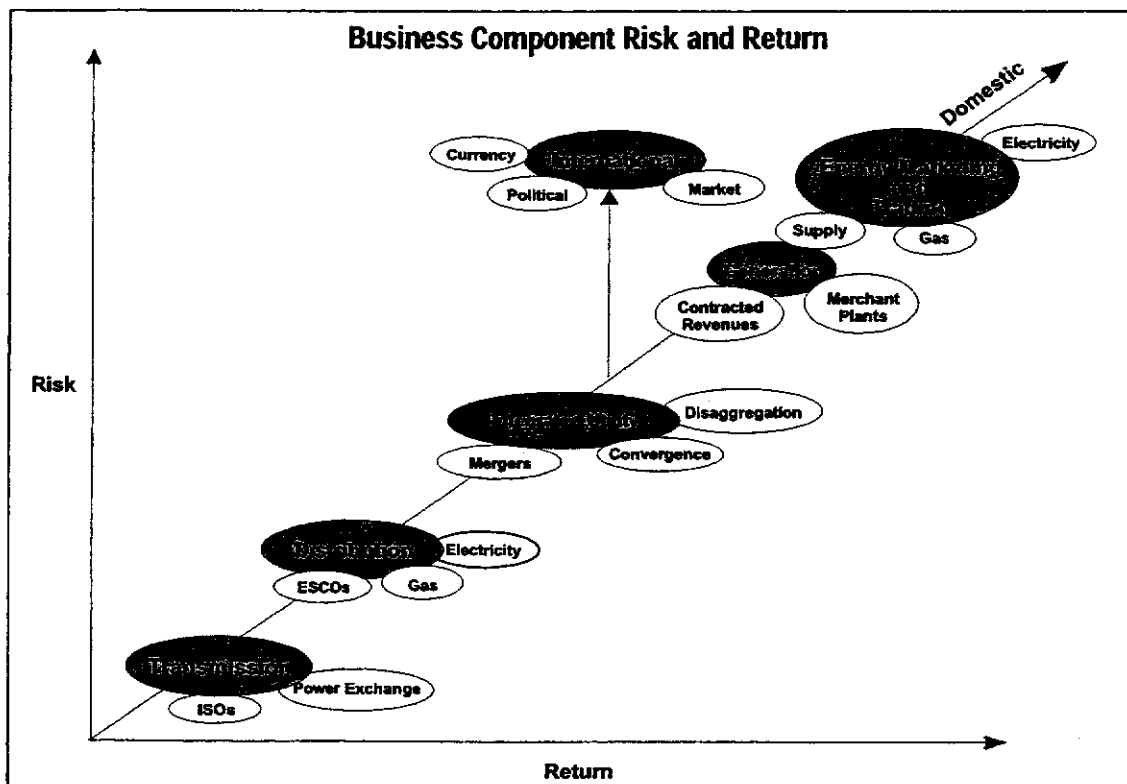
Still, Moody's views the market's reactions to the events of June as healthy for the energy trading business. Many firms are now reevaluating their power marketing operations. LG&E Energy, among the top ten power marketing firms in each of the past three years, announced that it was exiting the power marketing arena due to the demands on capital required by energy trading and booked a \$225 million second quarter 1998 loss related to power trades and to a reserve to close out contracts.

Others firms have strengthened their counterparty risk management practices. Tools to manage this risk include examination of financials for capital adequacy, insistence on guarantees from a more creditworthy parent or letters of credit, or provision of forms of collateral. Prepayment became an emergency credit protection in the days immediately following the first trade failures.

In the end, we still view this growing sector as an essential component of the developing, less - regulated energy market despite its high risks and low profits. Trading provides access to liquidity and the creativity to structure contracts closely tailored to specific customer requirements.

Moody's believes that success in power marketing is possible for those firms with both market savvy and sophisticated, effective risk management. However, both these skill bases carry high price tags. Therefore, capital is a primary requirement for any firm that chooses active involvement.

The following chart reflects general elements of risk and return present in various business components and management strategies. It is intended for illustrative purposes only rather than Moody's specific view of the risk and return relationship.



Management Strength, Depth and Vision Become Critical

Next to business line differentials, the strength and vision of management is perhaps the most important issue in determining each company's place within the credit quality distribution. Because the utility industry is experiencing unprecedented change, the quality and depth of management has grown in importance, to become the central qualitative factor which we assess in order to assign forward looking bond ratings. We develop our view of this intangible factor through frequent and often indepth contact with senior management in both their offices and ours.

We have observed that management teams are changing to meet evolving risk profiles. A management team which undertakes to operate a regulated distribution business will likely exhibit strengths vastly different from one managing a portfolio of competitive generating assets. As the strengths of the management teams diverge, so will bond ratings.

As the need for diverse talents becomes clear, companies recruit experienced executives from competitive industries, such as the financial, telecommunications, gas, and industrial sectors to bring new talents and fresh ideas in the early stages of reform, as well as to lead and shape the discrete business segments they have divested or reorganized.

FORMULATING STRATEGIES FOR COMPETITION, GROWTH, AND CHANGE

How does Moody's view management? When Moody's analyzes management and the corporate strategies it formulates for competition, growth and financial improvement, we look for original thinking, problem solving skills, and leadership qualities that can guide the culture change that is critical to any organization experiencing dramatic shifts in business profiles and risk parameters.

The actions of the company are evaluated in the context of the utility's corporate strategy as defined by senior management. Do the actions mirror what senior management has indicated to the company's stakeholders? Is strategic direction adding risk to the corporate profile, or shifting it? Does management recognize the obstacles it faces in pursuing its strategy and give proper weight to mitigants?

Moody's also looks for innovation. An important rating criterion is whether senior management has the flexibility to make changes to its strategy to respond to changes in its business environment. Are actions reactive or ahead of the curve? For example, although many states have yet to pass retail choice legislation or mandate the divestiture of generating assets, the more sophisticated companies have functionally disaggregated their businesses. In fact, some investor-owned utilities have required the discrete business segments (such as generation, transmission and distribution, energy services, power marketing, and non-regulated investments) to operate separately and be responsible for meeting their own strategic objectives and profitability goals. Others are divesting themselves entirely of one or more of these business lines to concentrate in, for instance, either transmission and distribution, or generation. In contrast, some continue to grapple with the appropriate direction for their organization.

In measuring a company's responsiveness to a changing business climate, Moody's considers the following actions to be important and perhaps even necessary under particular circumstances: cost reductions; common stock dividend adjustments; common stock buybacks and debt repayments; customer rate decreases; and new programs for attracting and retaining customers.

Most well-managed electric utilities have already implemented cost-cutting initiatives, including: renegotiating or buying out expensive power purchase contracts, retiring uneconomic or non-performing nuclear generating facilities, replacing steam generators for highly efficient nuclear plants to prolong their usefulness, outsourcing of certain operating functions, upgrading computer systems, replacing existing billing and metering systems, and other programs geared toward greater operating efficiency. They have also worked with regulators to become more competitive and/or to implement transition plans even in regions where deregulation is progressing slowly. A demonstrated commitment to reducing potential stranded costs is a critical management strength.

What management does with free cash flow and heightened liquidity from cost reductions is a critical factor. Choices range from reduction of potential stranded costs, which we view as a positive for all stakeholders, to stock repurchase programs and investment in non-regulated businesses in the U.S. and overseas, both of which we view with caution. Stock repurchase programs offer an alternative means to increase a company's equity returns, while investment in unregulated businesses offers potential growth opportunities. Bondholders do not benefit from either of these alternatives, and could suffer a diminution of cash flow strength to service debt or equity cushion to guard against unforeseen events.

GROWTH OUTSIDE CORE PRESENTS RISKS TO BONDHOLDERS

We are particularly concerned about management strategy in pursuing non-core or untraditional business activities both in the U.S. and abroad as a means of achieving growth. An unbalanced focus on non-U.S. investment may prevent management from devoting sufficient amounts of time and energy to improve the company's competitive position at home and to prepare the company for heightened competition in the U.S.

In addition, we are cautious about the level of risk adjusted returns a company is willing to accept in non-U.S. locations. Bondholders do not reap the benefits of higher earnings and returns stemming from a parent or holding company's foreign investments but can suffer from the pressure placed on a company's cash flow as a result of additional debt taken on to finance new investments. Non-U.S. investments are financed largely with debt instruments and, as a result, any earnings and cash flow from foreign operations will likely be used to service the acquisition debt or to pay shareholders in lieu of strengthening the equity cushion. Moreover, when ambitious growth in non-regulated energy investments increases a utility's debt leverage, and introduces a greater level of business risk for the company, credit quality is weakened.

However, not all domestic electric utilities are venturing abroad seeking investment opportunities to expand and enhance earnings and returns. For one thing, some companies simply lack the financial resources due to their smaller capital base. Secondly, these companies are much involved in reshaping their individual state reform initiatives, while preparing themselves for open competition in home markets. Finally, some companies are already immersed with their own mergers with or acquisitions of neighboring utilities.

INDEPENDENT POWER PRODUCERS TAKE ON RISK INTERNATIONALLY

A significant portion of the independent power producer universe, both non-regulated subsidiaries and independent companies, have chosen a strategy of international diversification. Additionally, in order to help diversify risk, several have chosen to branch out into electric distribution and transportation rather than stay strictly in generation.

Strategies employing international investments can increase the risk profile of an issuer because the assets, brown or green-field, tend to be in riskier markets in order to generate a higher rate of return to the parent. Such a strategy is important to stockholders, as it increases the opportunities for increased net cash flow at the parent level, driving up the value of the company. From a bondholder's perspective, however, cash flow derived from less creditworthy geographic areas of the world tends to be less predictable.

By way of example, the recent change in outlook on AES Corporation's Baa3 rating to negative was prompted by the downgrading of the Brazilian country ceiling for foreign currency bonds and notes to B2. Since AES derives a significant portion of its cash from investments in Brazil, the quality of the cash flows from Brazil to AES Corporation has been eroded as the creditworthiness of Brazil has deteriorated. Furthermore, AES' Brazilian assets are subject to a heightened level of refinancing risk as Brazil's lower credit quality drives investors out of the market.

The event risk of doing business in emerging markets keeps constant pressure on ratings of companies like AES Corporation (senior unsecured rating Baa3), CalEnergy Corporation (senior unsecured Ba1) and CMS Corporation (senior unsecured Ba3). Other companies employing a global strategy are Edison International (commercial paper rated P-1) through its subsidiary Edison Mission Energy (senior unsecured A3), EDF (Aaa), Endesa Spain (senior unsecured Aa2), InterGen (not rated), National Power, plc (senior unsecured rated A2), PowerGen (senior unsecured rated Aa3), Sith Energy (not rated), Southern Company (commercial paper rated P-1), and Tractebel (not rated). Continued economic and currency crisis conditions in the emerging markets will put further pressure on those most heavily exposed.

The method of financing international acquisitions or developing projects on a global basis has credit ramifications from two distinct fronts. Such investments are often financed in discreet subsidiaries. Debt is incurred at the subsidiary level as well as at the parent level. Lenders to the subsidiary commonly impose restrictions on dividends to the parent company, and can require all or a portion of excess cash flow to be used to repay debt at the subsidiary level. In effect, lenders to the subsidiary can restrict access by the parent to cash flow from the very operations it has invested in order to increase earnings and cash flow.

Understanding the covenant package in these types of structures can be a critical element in assessing the likelihood of timely repayment of obligations of the parent company. Examining financial statements may not reveal a problem immediately, because GAAP reporting requires earnings to be reported on a consolidated basis if the parent's ownership in an asset is the majority. On a consolidated basis, the investment may appear to be healthy. But in fact cash is being trapped at the asset level and the parent has no real access to the cash returns they anticipated from their investment.

Another issue is one of cash flow repatriation and taxation. Consolidated financial statements mask these risks, too. The cost of repatriating dividends from a profitable investment back to the ultimate parent can be very expensive if the tax treaties do not work in the owner's favor. Where borrowers and intermediate holding companies are domiciled are an important part of understanding the creditworthiness of a parent company.

Investment in non-US assets carries with it multiple risks to bondholders without the reward shareholders will receive from a successful venture. It is for this reason that Moody's regards global investment with caution. Companies heavily involved in such activity will continue to experience pressure on their ratings because of the difficulties that could arise in accessing cash flow when it is needed.

Electric Sector Ready for the Year 2000

Moody's believes that the North American electric energy sector will be technologically ready for the "Year 2000", the date January 1, 2000 (or Y2K). That is not to say that some minor glitches will not arise. But we believe that the power will not go out.

This belief is grounded on two assumptions. First, above and beyond all corporations' well-grounded concerns about legal liability, this industry is of such strategic importance that it is therefore subject to detailed oversight from regulators and politicians. As one Congressman put it during hearings on the subject, "without electricity [on January 1, 2000], everything else is moot". Major industrial firms have also attempted to assess their utilities' Y2K preparedness as the utilities are key suppliers.

Second, the sector's restructuring has not yet diminished its traditional focus on reliability. While the new (and still relatively small) independent power producers may still view reliability as a competitive issue, causing them to be less amenable to cooperation, the traditional IOUs still largely manage the grid. So they and their industry organizations have largely relied on their culture of cooperation to solve this huge issue.

A broad sampling of cost estimates to prepare systems for Y2K range from \$1-\$10 million for small utilities to nearly \$100 million for the largest. Yet these estimates can exaggerate the purely Y2K costs. Regulation penalized utilities for investing in available technology in the past, and some systems currently in use are as much as 25 years old. So utility managements preparing for competition have been actively using the good cash flow on the tail of completed construction cycles to upgrade or replace systems as opposed to recoding them, with the rationale that no regulator will fault them for spending on Y2K compliance.

Moody's views Y2K expenditures at US utilities as manageable and just one more challenge facing this industry, which is already reeling from the challenges of deregulation. Fortunately, here at the turn of the century the utilities generally have low capital spending requirements and minimal external financing needs. Therefore, strong cash flow and management of dividend and corporate finance policies have provided the financial flexibility to absorb the Y2K costs. Accounting for these costs varies, although the SEC requires expensing purely Y2K expenditures.

Moody's also sees minimal regulatory risk from preparation for the Year 2000. Few utilities are filing base rate cases, so the expenditures are not likely to attract additional regulatory scrutiny. Regulators are also highly unlikely to disallow this needed expenditure.

IOUs view the management of the grid and the generating and distribution systems as their #1 Y2K concern, closely followed by the customer billing systems. Computer coding within applications is the primary concern for billing, customer service, and other administrative systems. Harder to address because they are harder to find are the chips embedded in computer hardware at operating power plants and in transmission and distribution systems.

Utilities generally have pursued similar approaches in assessing, correcting, and testing for Y2K readiness across their corporations, having prioritized each facet into critical, important, and less critical categories (the latter including, for example, the copying machines or cell phones). These processes were generally in full swing by 1997. The majority will complete critical testing by July 1999.

All utilities will not certify the readiness of their suppliers due to the legal liability that entails and the lack of knowledge about and control over their suppliers' systems and Y2K plans. All are making substantial efforts to gain at least a high level of comfort that suppliers are preparing for the date by two or even three detailed, formal surveys of supplier initiatives. Some are even insisting on testing the critical suppliers' systems themselves.

Support from industry organizations helps this sector to compensate for the shortage of talent to address this issue. Edison Electric Institute, the trade association for IOUs, provides a focal point for resources and information. Power pools, such as those in New England, California, Texas, and in several other regions have also been effective staging grounds for Y2K preparation. The North American Electric Reliability Council is also pursuing major initiatives to ensure the grid's Y2K preparedness.

The Nuclear Regulatory Commission requires its plant operators to certify by August 1998 that they have plans in place to meet the Y2K challenges and to certify their plants' readiness by July 1, 1999. The NRC notes that safety is not a concern as safety-related systems do not rely on date-driven databases. A plan called *Nuclear Utility Year 2000 Readiness*, developed by the Nuclear Energy Institute and the Nuclear Utilities Software Management Group, draws on best practices from around the nation to provide guidelines on procedures, assessments, remediation, testing, and validation for nuclear power plants.

The Clinton administration has proposed legislation to encourage information-sharing, which has become more difficult with legal liability concerns and with new competitive pressures in those regions currently restructuring their electric sectors. Passage may take some time, but this type of legislation can only be helpful to the utilities given particularly the legal liability concerns they all feel.

Appendix I

State Restructuring Initiatives

Category A = Restructuring legislation passed, including authorization for securitization.

Category B = Restructuring legislation passed, without authorization for securitization.

Category C = No specific restructuring legislation, yet substantial progress due to regulatory initiatives.

State	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation
Alabama	Comprehensive legislation passed 9/96.	PUC approved plans of state's 3 major IOUs.	Choice for all retail customers began 3/1/98	10% for residential and commercial customers.	Yes, some IOUs have already sold certain generation assets.	Yes	Yes
Arizona	Comprehensive legislation signed 4/98.	Both UI and CL&P will have filed plans by Oct. 1.	Retail choice phase-in between 1/00 and 7/00.	Standard offer rate reductions of 10% from 12/96 levels.	Not required but necessary for support of stranded cost recovery efforts.	Yes	Permitted, but limited to recovery of generation-related regulatory assets and pp contracts.
Arkansas	Comprehensive legislation passed 12/97.	ICC approved CWE's request to issue securitization bonds; IP's request still pending before ICC.	Full retail access to be phased in by 5/1/02.	Varies by company depending on existing rates. Reductions will range from 5%-20%.	Not required but CWE divesting certain generation assets.	Yes	Yes
California	Comprehensive legislation signed 11/97.	Most IOUs have filed and received approvals for restructuring plans; WMECO's plan is currently under review.	Full choice for all customers began on 3/1/98.	10% for standard offer; additional 5% on 9/1/99.	Not required but necessary for support of stranded cost recovery efforts.	Yes	Yes
Colorado	Comprehensive legislation passed 5/97.	PSC issued interim orders allowing Montana Power & PacifiCorp to proceed with plans. Final orders pending. MDU Resources can defer compliance with legislation.	Full retail access to be phased in by 7/1/02.	Determined by PSC at later date.	Not required but Montana Power is divesting its generation assets.	Yes	Yes
Connecticut	Comprehensive legislation passed 12/96.	Each of state's IOUs filed plans with PUC; all orders appealed; delay in implementing retail choice possible, but unlikely.	Choice for two-thirds of customers to be phased in starting 1/99; other one-third 1/00.	To be determined by PUC for each IOU.	Not required but GPU system and Duquesne have proposed generation asset divestiture.	Yes	Yes
Delaware	Comprehensive legislation signed in 1996.	PUC approved divestiture plans for all state's IOUs during 1997. Standard offer prices approved 5/98.	Full competition effective 1/1/98.	Standard offer at a discount from previously bundled rates.	Mandatory to spin-off or sell 15% of generating assets. Narragansett Electric sold 100%; others trying to do same as well.	Yes	Yes

Appendix L (cont'd)

State Restructuring Initiatives

Category A = Restructuring legislation passed, including authorization for securitization.

Category B = Restructuring legislation passed, without authorization for securitization.

Category C = No specific restructuring legislation, yet substantial progress due to regulatory initiatives.

State	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation	Restructuring Legislation
Alabama	Comprehensive legislation signed on 6/97.	PUC to decide rate design, revenue requirement and stranded cost proceedings for utilities.	Full choice for all customers by March 1, 2000.	To be determined by PUC.	Divestiture required by 3/1/00.	Yes	Not Yet.
Arizona	Comprehensive legislation passed 7/97.	Plans to be filed by the state's IOUs by 2/99.	Full choice for all by 12/31/99 unless PSC decides to delay implementation.	To be determined	Not required but Sierra Pacific and Nevada Power plan to divest generation assets.	To be determined by PSC.	Not Yet.
Arkansas	Comprehensive legislation signed on 6/96.	PSNH's restructuring plan is being held up by a lawsuit filed by the company; Granite received approval of its plan.	SB 341 delayed competition indefinitely beyond original start date of 1998.	Subject to court rulings or negotiated settlement.	Subject to court rulings or negotiated settlement.	Yes	Not Yet.
California	Comprehensive legislation passed 4/97 and some revisions in 6/98.	IOU plans that may be approved by the OCC would still require legislative approval.	Legislation calls for retail choice for all by 7/1/02.	Rates capped at current levels during transition.	Not required.	OCC will determine amount to be recovered via transition charge.	Not Yet.
Colorado	Legislation implementing framework for retail competition. Details to follow in subsequent legislation.	Each of the state's IOUs taking their own approach.	The legislation calls for retail access to be phased in 1/1/02-1/1/04.	To be handled on a case-by-case basis for the state's IOUs.	Not required.	No specifics, but just and reasonable stranded costs shall be recoverable.	Not yet.

Appendix I (cont'd)

State Restructuring Initiatives

Category A = Restructuring legislation passed, including authorization for securitization.

Category B = Restructuring legislation passed, without authorization for securitization.

Category C = No specific restructuring legislation, yet substantial progress due to regulatory initiatives.

State	Restructuring Legislation	Restructuring Rules	Retail Access Phase	Individual Rate Freeze/Reduction Plans	IOUs Have Options	Yes/No	Not Yet/Yes
Alaska	None that is legally binding to the state's IOUs.	Restructuring Rules adopted by ACC in 1996; later amended in 8/98. Both of state's IOUs have filings pending with ACC.	Retail access phase in begins on 1/1/99; completed by 1/1/01. Retail choice phase in	Individual rate freeze/reduction plans in place.	IOUs have options; Tuscon plans to divest; APS does not.	Yes	Not Yet.
Arizona	None	PSC has approved restructuring plans for Con Ed; RG&E; O&R; NYSEG; CHGE; and NIMO.	Starts in 1998 for all utilities, but different start dates for each IOU.	Differs for each IOU.	Individual plans all require divestiture except RG&E's as a mitigant for gaining stranded cost recovery.	Yes	Although bills have been proposed, not yet.
California	None	Generic competition transition plan adopted by PSC on 12/97. Each of the state's 4 major IOUs have filed their own restructuring plans.	Retail competition phased in over 7/1/00-7/1/02.	Price cap approach suggested; rate reductions possible.	Not required but may be considered.	Included as part of 3 of 4 restructuring plans filed before the PSC.	Not yet, but recommended by PSC.
Colorado	None	PSC has established a framework for restructuring spelled out in several different orders.	Framework calls for phase-in of retail competition over 1998-2001.	To be determined.	Not required.	Yes	Not yet, but considered a possibility.
Connecticut	Legislation introduced 9/14/98; pending adoption.	BPU adopted the Energy Master Plan in 4/97. All the state's IOUs have filed their restructuring plans with the BPU. Final orders are still pending.	Retail Choice under proposed legislation would be phased in over four months beginning in the spring of 1999.	Ranging between 5%-10% in the near-term.	Not required but GPU has indicated intentions to do so.	Yes	Not yet, but will be considered as part of legislation recently introduced.
Delaware	None yet, but likely in 1999.	PUCT approved settlements with 3 utilities.	None specified yet.	Ranging between 1%-9%.	Legislation may use it to quantify stranded costs.	Depends on legislation.	Depends on legislation.

[1] Each NY IOU was required to file a separate restructuring plan.

Appendix II

1997 Actual Data for the Electric Industry (\$mil.)

Sr. Debt Rating+	Company	Revenue	Net Income	Dividend Payout %	EBIT/ Interest	FFO/ Interest	FFO % Capex	Def. Charges % Equity	Total Capital	Debt % Capital	Prof. Stock % Capital	Equity % Capital
Aaa	*Tennessee Valley Authority	5,552,000	8,000	0.00	1.10	1.50	129.75	61.03	30,900,000	87.10	0.00	12.90
	AVERAGE OF RATING GROUP	5,552,000	8,000	0.00	1.10	1.50	129.75	61.03	30,900,000	87.10	0.00	12.90
Aa2	AmerenCIPS	852,075	59,758	72.46	2.70	2.68	53.46	14.62	1,285,199	49.21	6.23	44.57
Aa2	*Central Illinois Light Company	546,854	46,151	85.55	3.18	6.00	205.88	6.91	698,648	42.91	9.46	47.63
Aa2	*Indianapolis Power & Light Company	776,427	130,642	73.67	4.18	6.50	313.97	16.65	1,496,167	43.55	0.61	55.84
Aa2	*Kentucky Utilities Co.	716,437	83,457	82.46	3.16	5.21	177.61	9.89	1,232,267	47.07	3.25	49.69
Aa2	*Louisville Gas & Electric Company	845,543	108,888	57.56	3.89	6.10	180.36	8.72	1,425,454	45.38	6.69	47.94
Aa2	*Madison Gas & Electric Company	264,648	22,523	91.86	3.10	6.13	254.52	15.52	344,346	47.46	0.00	52.54
Aa2	*Southern Indiana Gas & Electric Company	358,106	44,266	68.86	3.18	4.91	122.17	16.23	661,773	50.69	2.95	46.37
Aa2	*Southwestern Public Service Company	979,283	75,575	114.31	2.15	3.00	103.95	26.35	1,598,565	50.06	6.26	43.69
Aa2	Tampa Electric Company	1,438,700	148,100	98.92	3.23	4.84	164.26	20.40	2,212,000	42.96	0.00	57.04
Aa2	Wisconsin Electric Power Company	1,789,602	69,412	307.86	1.60	4.01	132.97	26.17	3,497,538	50.68	0.87	48.45
Aa2	*Wisconsin Power and Light Company	794,717	67,924	85.90	4.83	7.01	148.71	29.75	1,147,116	43.71	5.23	51.06
Aa2	*Wisconsin Public Service Corporation	690,478	61,631	90.67	3.46	5.95	223.14	17.18	841,440	39.59	6.09	54.33
	AVERAGE OF RATING GROUP	837,739	78,511	102.51	3.22	5.19	173.42	17.35	1,370,043	46.10	3.97	49.93
Aa3	AmerenUE	2,287,333	319,805	81.11	3.32	5.01	214.43	33.15	4,439,230	42.72	3.50	53.78
Aa3	Dayton Power & Light Company	1,254,400	171,100	69.26	4.16	4.48	270.15	49.72	2,271,100	42.60	1.01	56.40
Aa3	Duke Energy Corporation	16,308,900	901,600	80.57	4.42	5.54	161.77	35.33	15,312,800	44.26	6.51	49.24
Aa3	Florida Power & Light Company	6,132,000	608,000	101.81	3.76	8.15	294.74	9.18	7,680,000	34.38	2.94	62.68
Aa3	Florida Power Corporation	2,448,400	134,400	143.16	2.12	5.18	126.65	42.56	3,727,700	51.69	0.90	47.42
Aa3	*Mississippi Power Company	543,588	54,010	91.47	3.70	5.90	195.67	15.69	781,405	41.81	8.56	49.63
Aa3	Northern States Power Company (Minnesota)	2,733,746	226,249	91.81	2.56	5.25	167.25	19.52	5,075,715	45.39	7.89	46.73
Aa3	*Oklahoma Gas & Electric Company	1,191,690	118,709	91.31	3.13	5.39	248.06	11.06	1,617,580	44.32	3.05	52.63
Aa3	*Otter Tail Power Company	394,279	29,988	80.93	3.52	4.71	163.79	18.96	453,384	45.08	8.57	46.35
Aa3	*Southwestern Electric Power Company	939,869	92,254	100.45	3.11	5.31	184.22	11.03	1,421,830	40.55	9.89	49.56
	AVERAGE OF RATING GROUP	3,423,421	265,812	93.19	3.38	5.49	202.67	24.62	4,278,074	43.28	5.28	51.44
A1	Alabama Power Company	3,149,111	375,939	90.33	2.73	4.21	167.80	26.10	6,158,501	46.37	8.97	44.66
A1	Baltimore Gas and Electric Company	3,307,600	254,100	94.14	2.78	4.04	196.44	18.03	6,747,300	53.01	4.45	42.54
A1	*Black Hills Corporation	313,662	32,359	63.48	4.31	5.04	270.78	11.49	370,117	44.50	0.00	55.50
A1	Consolidated Edison Company of NY, Inc.	7,121,254	694,479	71.09	3.12	4.64	186.30	27.59	10,966,388	43.03	2.90	54.08
A1	Georgia Power Company	4,385,717	593,996	87.54	3.88	7.08	289.58	28.88	8,436,145	42.32	10.03	47.65
A1	*Gulf Power Company	625,856	57,610	112.14	3.38	5.80	238.43	16.68	879,729	45.16	6.10	48.73
A1	Kansas City Power & Light Co.	895,943	72,771	142.97	2.00	3.80	167.14	21.04	2,126,912	47.46	11.24	41.30
A1	Massachusetts Electric Company	1,624,085	62,399	42.28	2.88	5.86	192.23	9.08	909,233	43.23	1.73	55.04
A1	*Monongahela Power Company	628,311	80,529	58.09	3.06	4.51	175.11	35.67	1,148,397	46.45	6.44	47.10
A1	Narragansett Electric Company	520,038	25,631	53.03	2.49	3.76	166.43	18.94	509,534	40.21	2.51	57.28
A1	New England Power Company	1,677,903	142,468	89.42	3.91	6.00	352.82	49.32	1,761,895	45.92	2.25	51.83
A1	*Northwestern Corporation	918,070	23,411	71.99	2.24	2.88	263.94	169.58	835,663	51.83	28.24	19.84
A1	Pacific Gas & Electric Company	9,495,000	735,000	100.54	3.42	5.71	176.22	4.95	17,791,000	54.52	4.72	40.77
A1	*Potomac Edison Company	708,781	95,755	86.97	2.90	4.30	214.93	16.71	1,334,971	47.10	1.23	51.67
A1	Potomac Electric Power Company	1,863,510	165,251	118.98	2.19	3.49	157.63	35.60	4,235,005	49.72	6.29	43.99
A1	Public Service Company of Oklahoma	712,690	50,053	118.90	2.41	5.18	181.52	11.59	981,208	43.49	8.18	48.33
A1	*San Diego Gas & Electric Company	2,167,548	231,650	110.59	3.67	7.65	298.74	22.45	3,351,236	55.51	3.09	41.40
A1	*Savannah Electric & Power Company	226,277	23,847	85.97	3.13	4.96	256.16	25.05	375,241	43.87	9.33	46.81
A1	*South Carolina Electric & Gas Company	1,338,000	186,000	75.81	2.88	4.85	167.67	31.38	2,938,000	45.03	5.72	49.25
A1	Southern California Edison Company	7,953,386	576,106	324.93	2.33	5.22	274.94	65.19	11,576,335	61.85	3.96	34.19
A1	*West Penn Power Company	1,082,162	134,665	72.00	2.91	4.02	166.95	37.61	2,034,600	47.08	3.92	49.00
	AVERAGE OF RATING GROUP	2,414,995	219,715	98.63	2.98	4.90	217.23	32.51	4,069,877	47.51	6.25	46.24

1997 Actual Data for the Electric Industry (\$mil.)

Sr. Debt Rating+	Company	Revenue	Net Income	Dividend Payout %	EBIT/ Interest	FFO/ Interest	FFO % Capex	Def. Charges % Equity	Total Capital	Debt % Capital	Pref. Stock % Capital	Equity % Capital
A2	Carolina Power & Light Company	3,024,089	382,265	72.68	3.10	6.14	240.73	42.30	5,501,818	47.69	1.08	51.23
A2	*Central Hudson Gas & Electric Corporation	520,277	51,856	77.96	3.06	5.49	272.65	34.69	896,280	40.52	6.25	53.23
A2	*Cleco Corporation	456,245	50,402	74.17	2.82	4.79	140.53	56.17	841,323	49.34	2.08	48.58
A2	*Delmarva Power & Light Co.	1,423,502	101,218	92.68	3.17	3.53	121.71	35.52	2,238,459	50.23	7.14	42.64
A2	*Empire District Electric Company, The	215,311	21,377	110.69	2.26	3.92	92.98	19.11	499,321	49.54	6.59	43.87
A2	Idaho Power Company	748,503	87,098	80.24	3.28	3.55	163.74	59.10	1,609,787	49.15	6.63	44.22
A2	Northern Indiana Public Service Company	1,752,382	188,081	98.78	3.42	6.34	249.00	29.83	2,407,772	51.90	5.81	42.29
A2	PacifiCorp	6,278,000	205,400	166.12	1.73	2.77	133.92	41.31	9,871,900	50.34	5.89	43.77
A2	Portland General Electric Company	1,416,000	124,000	52.42	2.70	4.81	156.67	92.75	1,948,000	51.75	1.54	46.72
A2	Virginia Electric and Power Company	5,079,000	433,400	87.66	3.28	4.84	304.56	22.54	9,014,400	45.20	9.14	45.66
A2	*West Texas Utilities Company	397,778	22,402	116.89	1.82	4.12	247.58	23.45	540,052	51.60	0.46	47.95
	AVERAGE OF RATING GROUP	1,937,372	151,581	93.66	2.78	4.57	193.10	41.52	3,215,374	48.84	4.78	46.38
A3	Appalachian Power Company	1,720,010	113,508	100.82	2.01	3.25	123.07	44.70	2,747,942	59.13	1.53	39.34
A3	Atlantic City Electric Company	1,084,890	80,926	105.87	3.19	3.91	231.97	39.97	1,807,055	49.26	7.41	43.33
A3	Central Power and Light Company	1,376,282	121,350	138.15	2.07	3.97	294.35	89.26	3,193,421	46.13	9.81	44.07
A3	Cincinnati Gas & Electric Company (The)	2,451,876	238,285	71.51	2.95	4.75	288.65	47.88	3,257,066	49.91	0.64	49.45
A3	*Columbus Southern Power Company	1,139,604	116,937	67.29	2.51	3.73	197.45	56.72	1,812,510	57.17	1.38	41.45
A3	Detroit Edison Company	3,657,000	405,000	81.73	3.37	4.60	244.19	29.57	7,383,000	51.61	1.95	46.45
A3	*Hawaiian Electric Company, Inc.	1,098,755	78,189	74.66	2.67	3.99	126.59	19.58	1,623,905	44.54	8.10	47.37
A3	Houston Industries Inc.	6,873,385	420,948	96.28	2.64	4.41	412.45	94.90	12,852,857	59.09	2.89	38.02
A3	*MidAmerican Energy Company	1,682,606	119,453	106.31	2.49	5.11	217.17	52.78	2,334,670	49.99	7.79	42.22
A3	Ohio Power Company	1,965,818	206,042	96.74	3.53	6.08	242.87	45.94	2,607,273	46.19	1.13	52.69
A3	*Orange & Rockland Utilities, Inc.	648,774	42,138	90.32	2.32	3.93	130.36	40.86	906,788	53.73	4.77	41.50
A3	PP&L, Inc.	3,049,000	308,000	111.69	2.69	4.87	258.06	52.14	6,064,000	45.12	11.81	43.07
A3	*PSI Energy, Inc.	1,958,469	120,504	94.27	2.54	5.07	244.89	52.79	2,313,361	48.35	6.80	44.86
A3	*Pennsylvania Electric Company	1,052,936	94,358	63.59	2.78	4.08	178.47	57.99	1,716,994	46.83	7.09	46.09
A3	*Public Service Company of Colorado	2,229,643	192,290	77.11	2.39	3.25	91.04	23.27	3,744,507	51.91	4.79	43.30
A3	*Public Service Electric and Gas Company	6,125,000	513,000	104.29	2.41	4.00	218.27	37.64	10,542,000	50.75	6.48	42.77
A3	*Rochester Gas & Electric Corp.	1,036,638	89,555	78.09	2.85	5.20	256.45	53.47	1,527,678	41.72	5.37	52.91
A3	*Sierra Pacific Power Company	657,540	77,668	97.16	2.87	4.20	95.57	22.67	1,443,514	47.27	8.43	44.31
A3	*Washington Water Power Company (The)	1,302,172	109,405	68.85	3.65	3.94	219.08	40.68	1,665,997	45.75	9.30	44.95
A3	*Western Resources, Inc.	2,151,765	489,175	28.97	5.52	0.38	-57.08	99.57	4,913,016	49.66	9.35	41.00
	AVERAGE OF RATING GROUP	2,162,108	196,837	87.69	2.87	4.13	200.89	50.12	3,722,878	48.70	5.84	44.46
Baa1	Arizona Public Service Company	1,878,553	238,690	71.22	2.49	4.99	205.03	61.55	4,208,465	51.99	4.07	43.94
Baa1	Boston Edison Company	1,776,233	131,493	79.82	2.34	4.19	298.55	23.80	2,531,303	51.23	6.36	42.41
Baa1	*Canal Electric Company	214,123	14,828	96.57	2.61	4.48	430.75	27.32	204,872	51.42	0	48.58
Baa1	*Duquesne Light Company	1,164,941	137,798	97.22	2.72	4.81	357.99	71.98	2,546,135	51.68	8.90	39.43
Baa1	*Eastern Edison Company	435,014	27,059	178.23	2.53	3.38	285.01	67.86	473,246	48.00	5.84	46.16
Baa1	Illinois Power Company	1,773,900	129,500	88.50	2.13	3.93	168.51	14.82	3,635,000	57.27	6.99	35.74
Baa1	Indiana Michigan Power Company	1,391,917	141,004	93.09	3.24	5.12	220.47	40.41	2,348,620	51.22	3.32	45.47
Baa1	Jersey Central Power & Light Company	2,093,972	200,638	74.76	3.10	5.22	257.30	62.35	3,174,850	43.48	8.01	48.51
Baa1	*Kentucky Power Company	359,543	20,746	128.99	1.81	3.15	82.77	38.95	634,827	59.47	0	40.53
Baa1	*Metropolitan Edison Company	943,109	93,034	85.99	3.00	4.59	207.41	80.31	1,512,247	45.14	7.41	47.45
Baa1	*Minnesota Power, Inc.	953,600	75,600	85.32	2.30	3.30	276.92	42.70	1,576,600	51.96	6.76	41.29
Baa1	*Montana Power Company	1,023,597	124,942	72.92	4.59	5.11	76.52	36.77	2,003,028	43.37	6.12	50.50
Baa1	New York State Electric and Gas Corporation	2,129,989	175,211	59.93	3.45	4.72	370.13	33.65	3,509,199	44.07	4.54	51.39
Baa1	PECO Energy Company	4,617,901	319,754	132.23	2.69	4.08	233.93	226.18	7,866,524	57.94	7.40	34.66
Baa1	*Puget Sound Energy, Inc.	1,676,902	108,363	156.78	1.98	2.52	72.93	45.28	3,466,944	52.94	7.89	39.17
Baa1	Texas Utilities Electric Company	6,135,417	745,024	36.62	2.58	4.09	363.68	29.60	13,734,406	46.68	7.46	45.86
	AVERAGE OF RATING GROUP	1,785,544	187,730	96.14	2.72	4.23	244.24	56.47	3,338,142	50.49	5.89	43.82